# DRAFT

**PREVENTION OF SIGNIFICANT DETERIORATION PERMIT**

**STATIONARY SOURCE PERMIT TO CONSTRUCT AND OPERATE**
**This permit includes designated equipment to**
**New Source Performance Standards (NSPS).**

This permit replaces your permit dated July 30, 2004,
as amended March 29, 2006 and June 5, 2007.

In compliance with the Federal Clean Air Act and the Commonwealth of Virginia Regulations for the Control and Abatement of Air Pollution,

CPV Warren LLC
8403 Colesville Road, Suite 915
Silver Spring, Maryland 20910
Registration No.: 81391
Plant ID No.: 51-187-0041

is authorized to construct and operate

an electric power generation facility

located

Lots 5, 6, 7, 8, 9 and 10, Warren Industrial Park
Warren County

in accordance with the Conditions of this permit.

Approved on July 30, 2004

Amended on March 29, 2006 and June 5, 2007

Amended on ***DRAFT***

Regional Director

Permit consists of 31 pages.
Permit Conditions 1 to 65.
Source Testing Report Format.

PERMIT CONDITIONS - the regulatory reference or authority for each condition is listed in parentheses ( ) after each condition. All parts per million (ppm) are parts per million by volume on a dry gas basis (ppmvd), corrected to 15 percent oxygen, unless otherwise stated. All heat inputs in British thermal units (Btu) are based on higher heating values.

## INTRODUCTION

This permit approval is based on the permit applications dated December 11, 2001, March 16, 2006, May 8, 2007 and July 11, 2007 including amendment information dated February 18, 2002, April 1, 2002, February 4, 2003, March 26, 2003, April 7, 2003, April 23, 2003, May 21, 2003, June 9, 2003, September 12, 2003, and May 18, 2004, and supplemental information dated November 14, 2003, December 30, 2005, January 25, 2006, February 16, 2006 and March 6, 2006. Any changes in the permit application specifications or any existing facilities which alter the impact of the facility on air quality may require a permit. Failure to obtain such a permit prior to construction may result in enforcement action. In addition, this facility may be subject to additional applicable requirements not listed in this permit.

Words or terms used in this permit shall have meanings as provided in 9 VAC 5-10-20 of the State Air Pollution Control Board Regulations for the Control and Abatement of Air Pollution. The regulatory reference or authority for each condition is listed in parentheses () after each condition.

Annual requirements to fulfill legal obligations to maintain current stationary source emissions data will necessitate a prompt response by the permittee to requests by the DEQ or the Board for information to include, as appropriate: process and production data; changes in control equipment; and operating schedules. Such requests for information from the DEQ will either be in writing or by personal contact.

The availability of information submitted to the DEQ or the Board will be governed by applicable provisions of the Freedom of Information Act, §§ 2.2-3700 through 2.2-3714 of the Code of Virginia, § 10.1-1314 (addressing information provided to the Board) of the Code of Virginia, and 9 VAC 5-170-60 of the State Air Pollution Control Board Regulations. Information provided to federal officials is subject to appropriate federal law and regulations governing confidentiality of such information.

**This permit authorizes one of three possible scenarios for the final configuration of the electrical power generation facility:**

- **Scenario 1 consists of a "one-on-one" combustion turbine (CT) generator configuration with two General Electric CT generators, Model 7FA, two heat recovery steam generators, and two steam turbines.**

- **Scenario 2 consists of a "two-on-one" CT generator configuration with two General Electric CT generators, Model 207FA, two heat recovery steam generators, one steam turbine, and one auxiliary boiler.**

- **Scenario 3 consists of a "two-on-one" CT generator configuration with two Siemens CT generators, Model SGT6-5000F, two heat recovery steam generators, one steam turbine, and one auxiliary boiler.**

**Unless a permit condition specifies a scenario, each permit condition is applicable to operation under any of the three scenarios. If a permit condition specifies one or more scenarios, it is applicable only to operation under the specified scenario(s).**

## PROCESS REQUIREMENTS

1. **Equipment List**

   a. **Scenario 1** - Equipment to be constructed at this facility consists of:

      - two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:

        - one General Electric natural-gas-fired CT generator, Model 7FA, rated at 180,000 KW (Combustion Generator Turbine only) and 1,717 million Btu per hour heat input (CT1 & CT2) (NSPS Subpart KKKK);

        - one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1 & DB2) (NSPS Subpart KKKK);

      - one diesel-fired emergency fire water pump, rated at 2.3 million Btu per hour heat input (EG1) (NSPS Subpart IIII); and

      - one diesel-fired emergency generator, rated at 1500 KW (EG2) (NSPS Subpart IIII).

      Exempt equipment to be constructed at this facility consists of:

      - one 6,000 gallon distillate oil storage tank.

   b. **Scenario 2** - Equipment to be constructed at this facility consists of:

      - two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:

        - one General Electric natural-gas-fired combustion turbine (CT) generator, Model 207FA, rated at 286,200 KW (Combustion Generator Turbine plus Steam Turbine Generator) and 1,944 million Btu per hour heat input (CT1 & CT2) (NSPS Subpart KKKK);

- one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 500 million Btu per hour heat input when firing natural gas (DB1 & DB2) (NSPS Subpart KKKK);

– one natural gas -fired auxiliary boiler, rated at 97 million Btu per hour heat input (AB1) (NSPS Subpart Dc);

– one diesel-fired emergency fire water pump, rated at 2.1 million Btu per hour heat input (EG1) (NSPS Subpart IIII); and

– one diesel-fired emergency generator, rated at 1500 KW (EG2) (NSPS Subpart IIII).

Exempt equipment to be constructed at this facility consists of:

one 6,000 gallon distillate oil storage tank.

c. **Scenario 3** - Equipment to be constructed at this facility consists of:

– two combined cycle power generating units (CC1 & CC2) where each unit includes the following emission units:

- one Siemens natural-gas-fired combustion turbine (CT) generator, Model SGT6-5000F, rated at 311,800 KW (Combustion Generator Turbine plus Steam Turbine Generator) and 2,204 million Btu per hour heat input (CT1 & CT2) (NSPS Subpart KKKK);

- one heat recovery steam generator (HRSG) with supplementary natural gas-fired duct burners, each duct burner with a design rating of 210 million Btu per hour heat input when firing natural gas (DB1 & DB2) (NSPS Subpart KKKK);

– one natural gas -fired auxiliary boiler, rated at 62 million Btu per hour heat input (AB1) (NSPS Subpart Dc);

– one diesel-fired emergency fire water pump, rated at 2.1 million Btu per hour heat input (EG1) (NSPS Subpart IIII); and

– one diesel-fired emergency generator, rated at 1500 KW (EG2) (NSPS Subpart IIII).

Exempt equipment to be constructed at this facility consists of:

- one 6,000 gallon distillate oil storage tank.

(9 VAC 5-80-1100 and 9 VAC 5-80-1605 A)

2. **Emission Controls: Nitrogen Oxides** – Oxides of nitrogen ($NO_x$) emissions from each CT (CT1 & CT2) and HRSG duct burner (DB1 & DB2) shall be controlled by use of a two-stage, lean pre-mix dry low-$NO_x$ combustor, a selective catalytic reduction (SCR) control system using ammonia injection, and good combustion practice. The SCR system shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 15).
(9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1705 B)

3. **Emission Controls: Carbon Monoxide** – Carbon monoxide (CO) emissions from each CT (CT1 & CT2) and HRSG duct burner (DB1 & DB2) shall be controlled by an oxidation catalyst and good combustion practice. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 15).
(9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1705 B)

4. **Emission Controls: Volatile Organic Compounds** – Volatile Organic Compound (VOC) emissions from each CT (CT1 & CT2) and HRSG duct burner (DB1 & DB2) shall be controlled by an oxidation catalyst. The oxidation catalyst shall be provided with adequate access for inspection and shall be in operation when the turbines are in normal operating mode (at all times except during startup and shutdown, as defined in Condition 15).
(9 VAC 5-50-260, 9 VAC 5-80-1180 and 9 VAC 5-80-1705 B)

5. **Emission Controls: Nitrogen Oxides (Scenarios 2 and 3)** – Oxides of nitrogen ($NO_x$) emissions from the auxiliary boiler (AB1) shall be controlled by low $NO_x$ burners and flue gas recirculation.
(9 VAC 5-80-1180)

6. **Monitoring Devices: SCR** - Each SCR system shall be equipped with devices to continuously measure and record ammonia feed rate, gas stream flow rate, and catalyst bed inlet gas temperature. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, as a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the SCR system is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, and 9 VAC 5-80-1705 B)

7. **Monitoring Devices: Oxidation Catalyst** - Each oxidation catalyst shall be equipped with a device to continuously measure and record temperature at the catalyst bed inlet and outlet. Each monitoring device shall be installed, maintained, calibrated and operated in accordance with approved procedures that shall include, at a minimum, the manufacturer's written requirements or recommendations. Each monitoring device shall be provided with adequate access for inspection and shall be in operation when the oxidation catalyst is operating.
(9 VAC 5-80-1180, 9 VAC 5-50-20 C, 9 VAC 5-50-260, and 9 VAC 5-80-1705 B)

8. **Monitoring Device Observation: SCR** – The devices used to continuously measure ammonia feed rate, gas stream flow rate, and SCR catalyst bed inlet gas temperature shall be observed by the permittee with a frequency sufficient to ensure good performance of the SCR system but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

9. **Monitoring Device Observation: Oxidation Catalyst** - The devices used to continuously measure catalyst bed inlet and outlet gas temperatures for each oxidation catalyst shall be observed by the permittee with a frequency sufficient to ensure good performance of the oxidation catalyst but not less than once per day of operation. The permittee shall continuously record measurements from the control equipment monitoring devices.
(9 VAC 5-50-50 H)

**<u>OPERATING/EMISSION LIMITATIONS – COMBINED CYCLE UNITS (CC1 & CC2)</u>**

10. **Fuel** - The approved fuel for each CT (CT1 & CT2) and each HRSG duct burner (DB1 & DB2) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions as specified in 40 CFR 72.2 (68°F and 29.92 in Hg). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 9 VAC 5-50-260, and 40 CFR 60.4330(a)(2))

11. **Fuel Throughput** – The combustion turbines and duct burners combined shall consume no more than the following throughput of natural gas per year:

| Scenario | Annual throughput |
|---|---|
| 1 | 35,920 x $10^6$ scf |
| 2 | 33,920 x $10^6$ scf |
| 3 | 34,942 x $10^6$ scf |

Throughput shall be calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by

adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

12. **Fuel Monitoring** – The permittee shall use the fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the total sulfur content for natural gas being fired at the electric power generation facility is 0.0003 percent by weight or less (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet), to demonstrate that potential sulfur dioxide emissions shall not exceed the limits specified in Condition 13.
(9 VAC 5-80-1180, 9 VAC 5-50-410 and 40 CFR 60.4365(a))

13. **Short-Term Emission Limits** - Emissions from the operation of each combined cycle power generating unit (CC1 & CC2) shall not exceed the limits specified below:

a. Scenario 1

| | Short term emission limits |
|---|---|
| PM-10 (includes condensable PM) | ▪ 0.013 lb/MMBtu |
| Sulfur dioxide | ▪ 0.0003 lb/MMBtu |
| Oxides of nitrogen (as $NO_2$) | ▪ 17.9 lbs/hr<br>▪ 2.0 ppmvd |
| Carbon monoxide | ▪ 1.3 ppmvd without power augmentation<br>▪ 7.2 lbs/hr and 1.8 ppmvd with power augmentation and without duct burner firing<br>▪ 12.8 lbs/hr and 2.5 ppmvd with power augmentation and duct burner firing |
| Volatile organic compounds | ▪ 0.7 ppmvd without duct burner firing<br>▪ 1.0 ppmvd with duct burner firing<br>▪ 1.4 ppmvd with duct burner firing and power augmentation |
| Sulfuric acid mist ($H_2SO_4$) | ▪ 0.0001 lb/MMBtu |

b. Scenario 2

| | Short term emission limits |
|---|---|
| PM-10 (includes condensable PM) | ▪ 12.45 lbs/hr and 0.0078 lb/MMBtu without duct burner firing (peak load)<br>▪ 17.56 lbs/hr and 0.0084 lb/MMBtu with duct burner firing (peak load)<br>▪ 12.38 lbs/hr and 0.0091 lb/MMBtu (80% load)<br>▪ 12.32 lbs/hr and 0.0107 lb/MMBtu (60% load) |
| Sulfur dioxide | ▪ 0.00017 lb/MMBtu |

| | |
|---|---|
| Oxides of nitrogen (as $NO_2$) | ▪ 2.0 ppmvd and 14.3 lbs/hr without duct burner firing<br>▪ 2.0 ppmvd and 17.9 lbs/hr with duct burner firing |
| Carbon monoxide | ▪ 1.2 ppmvd and 3.3 lbs/hr without duct burner firing<br>▪ 1.5 ppmvd and 7.3 lbs/hr with duct burner firing |
| Volatile organic compounds | ▪ 0.7 ppmvd and 0.9 lb/hr without duct burner firing<br>▪ 1.5 ppmvd and 3.9 lbs/hr with duct burner firing |
| Sulfuric acid mist ($H_2SO_4$) | ▪ 0.00016 lb/MMBtu |

c. Scenario 3

| | Short term emission limits |
|---|---|
| PM-10 (includes condensable PM) | ▪ 9.90 lbs/hr and 0.0050 lb/MMBtu without duct burner firing<br>▪ 11.30 lbs/hr and 0.0049 lb/MMBtu with duct burner firing |
| Sulfur dioxide | ▪ 0.00034 lb/MMBtu without duct burner firing<br>▪ 0.00031 lb/MMBtu with duct burner firing |
| Oxides of nitrogen (as $NO_2$) | ▪ 2.0 ppmvd and 16.5 lbs/hr without duct burner firing<br>▪ 2.0 ppmvd and 17.4 lbs/hr with duct burner firing |
| Carbon monoxide | ▪ 1.8 ppmvd and 7.2 lbs/hr without duct burner firing<br>▪ 2.5 ppmvd and 12.8 lbs/hr with duct burner firing |
| Volatile organic compounds | ▪ 0.7 ppmvd and 2.1 lb/hr without duct burner firing<br>▪ 1.4 ppmvd and 4.3 lbs/hr with duct burner firing |
| Sulfuric acid mist ($H_2SO_4$) | ▪ 0.00013 lb/MMBtu without duct burner firing<br>▪ 0.00012 lb/MMBtu with duct burner firing |

Where:

ppmvd ≡ parts per million by volume on a dry gas basis, corrected to 15 percent $O_2$.

Short-term emission limits represent averages for a three-hour sampling period except for nitrogen oxides, which shall be calculated as a one-hour average.

Unless otherwise specified, limits apply at all times except during startup, shutdown, and malfunction. Periods considered startup and shutdown are defined in Condition 15 of this permit.

Peak load means 100 percent of the manufacturer's design capacity of the combustion turbine at International Organization for Standardization (ISO) conditions.

(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1715, 40 CFR 60.4320 and 40 CFR 60.4330)

14. **Annual Emission Limits –** Total emissions from the operation of both combined cycle power generating units (CC1 & CC2) including duct burners shall not exceed the limits specified below:

| Pollutant | Annual emissions (tons) | | |
|---|---|---|---|
| | Scenario 1 | Scenario 2 | Scenario 3 |
| PM-10 (includes condensable PM) | 134.0 | 129.1 | 86.3 |
| Sulfur Dioxide | 5.7 | 3.0 | 6.0 |
| Oxides of Nitrogen (as $NO_2$) | 141.8 | 136.5 | 137.5 |
| Carbon Monoxide | 97.2 | 101.7 | 132.4 |
| Volatile Organic Compounds | 22.9 | 30.2 | 38.9 |
| Sulfuric Acid Mist ($H_2SO_4$) | 1.9 | 2.7 | 2.4 |

Annual emission limits are derived from the estimated overall emission contribution from operating limits, including periods of startup and shutdown. Annual emissions shall be calculated monthly as the sum of each consecutive 12-month period. Exceedance of the operating limits may be considered credible evidence of the exceedance of emission limits.
(9 VAC 5-50-260, 9 VAC 5-50-410, 9 VAC 5-80-1705, 9 VAC 5-80-1180 and 9 VAC 5-80-1715)

15. **Startup/Shutdown** – The short-term emission limits contained in Condition 13 apply at all times except during periods of startup and shutdown.

a. Startup and shutdown periods are defined as follows:

i. Cold Startup – refers to restarts made 72 hours or more after shutdown. Exclusion from the short-term emissions limits for cold startup periods shall not exceed 4.0 hours per occurrence.

ii. Warm Startup – refers to restarts made more than 8 but less than 72 hours after shutdown. Exclusion from the short-term emissions limits for warm startup periods shall not exceed 2.1 hours per occurrence.

iii. Hot Startup – refers to restarts made 8 hours or less after shutdown. Exclusion from the short-term emissions limits for hot startup periods shall not exceed 1.5 hours per occurrence.

iv. Shutdown – refers to the period between the time the turbine load drops below 50% operating level and the fuel supply to the turbine is cut. Exclusion from the short-term emissions limits for shutdown shall not exceed 1.5 hours per occurrence (Scenario 1) or 0.5 hours per occurrence (Scenarios 2 and 3).

b. The permittee shall operate the CEMS during periods of startup and shutdown.

c. The permittee shall record the time, date and duration of each startup and shutdown period.

d. The permittee shall operate the facility so as to minimize the frequency and duration of startup and shutdown events.

(9 VAC 5-50-260, 9 VAC 5-80-1715, 9 VAC 5-80-1180 and 9 VAC 5-80-1705)

16. **Emission Limits: Duct Burners** – Emissions from the operation of each duct burner (DB1 & DB2) for each combined cycle system shall not exceed 54 ppm of oxides of nitrogen (expressed as $NO_2$) at 15 percent $O_2$.
(9 VAC 5-80-1180, 9 VAC 5-50-410 and 40 CFR 60.4320)

17. **Pollution Prevention: Ammonia** – The permittee shall minimize emissions of ammonia resulting from unreacted ammonia emitted from the SCR (ammonia slip) to 5 parts per million by volume, dry basis, corrected to 15% $O_2$. Compliance with the ammonia slip limit shall be determined based on a three-hour block average. At least three months prior to startup, the permittee shall submit a plan for approval for monitoring the ammonia slip and demonstrating compliance with the ammonia slip limit from each SCR system to the Director, Valley Region. Implementation of the plan shall commence upon startup of the facility. The permittee shall demonstrate compliance with the ammonia slip limit at least 95 percent of the time the SCR is operating. Compliance with the 95% time percentage requirement shall be calculated daily and based on a 30-day rolling period. Alternatively, if on a given day less than 100 hours of operation has occurred in the prior 30 days, compliance with the 95% limits may be based on the most recent 100 hours of SCR operation.
(9 VAC 5-80-1180, 9 VAC 5-170-160 and Virginia Pollution Prevention Act, § 10.1-1425.11)

18. **Pollution Prevention: SCR Replacement** – At least two years prior to a planned replacement of the entire SCR system, the permittee shall conduct a study of technically and economically feasible and commercially available $NO_x$ control devices. The study shall include the cost effectiveness for each control device evaluated, including SCR. The

results of the evaluation shall be submitted to the Director, Valley Region, prior to ordering a replacement system. In the event the permittee wants to replace the SCR with an alternative control device, such a replacement may not require a permit to modify and operate, providing the new system provides an equal or better level of control.
(9 VAC 5-80-1180, 9 VAC 5-170-160 and Virginia Pollution Prevention Act, § 10.1-1425.11)

19. **Visible Emission Limit** - Visible emissions from each combined cycle (CC1 and CC2) stack shall not exceed 10 percent opacity, except during one six-minute period in any one hour in which visible emissions shall not exceed 20 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A). This condition applies at all times except during startup, shutdown (as defined in Condition 15), and malfunction.
(9 VAC 5-50-20, 9 VAC 5-50-260 and 9 VAC 5-80-1705)

20. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the CTs and duct burners described in Condition 1 (CT1, CT2, DB1 & DB2) shall be operated in compliance with the requirements of 40 CFR 60, Subpart KKKK.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

21. **CAIR (Clean Air Interstate Rule) $NO_x$ Annual Trading Requirements -** A review of the air emission units included in this permit approval has determined that the combined-cycle units listed in Condition 1 meet the definition of a CAIR $NO_x$ Unit and fall subject to the CAIR $NO_x$ emission limitations under 9 VAC 5-140-1040 or for opt-in sources 9 VAC 5-140-1800. As required by 9 VAC 5-140-1200 A, for each CAIR $NO_x$ source required to have a federally enforceable permit, such permit will include the CAIR permit to be administered by the permitting authority. The following requirements pertain to the CAIR $NO_x$ Annual Trading program:

    a. Prior to operation commencement, the permittee shall obtain a CAIR permit, as required by 9 VAC 5-140-1200 A, to be administrated by the Virginia Department of Environmental Quality (VADEQ) under the authority of 9 VAC 5-80-360 *et seq.*, and 9 VAC 5-140-1010 *et seq.*

    b. As of commencement of operation of the permitted facility (the first day either of the combustion turbines burns fuel), the permittee shall comply with the requirements of the CAIR $NO_x$ emission limitations under 9 VAC 5-140-1040.

    c. Each combined-cycle unit (combustion turbine and heat recovery steam generator) in Condition 1 meets the applicability requirements as provided in 9 VAC 5-140-1040 A.1 and A.2. The permittee shall meet the monitoring, emission calculation, recordkeeping, reporting, and testing requirements as applicable under 9 VAC 5 Chapter 140, Part II, Article 8.

(9 VAC 5-80-1180 and 9 VAC 5 Chapter 140 Part II)

22. **$NO_x$ Offsets -** Pursuant to the State Air Pollution Control Board's June 29, 2004 directive, the permittee shall obtain $NO_x$ offsets for the purpose of showing a demonstrable benefit to Shenandoah National Park, in accordance with the following:

a. The permittee shall secure a reduction in $NO_x$ emissions of no less than 175 tons from a source or sources in the manner prescribed as follows:

i. The offsets shall be creditable (i.e., not otherwise required by law, regulation, or existing permit), quantifiable, permanent, and federally enforceable as defined in 40 C.F.R. Part 51, App. S § II.A.12. The baseline for calculating the offsets shall be determined pursuant to the method set forth in 40 C.F.R. Part 51, App. S § IV.C.

ii. In addition to satisfying the geographical and other requirements of Condition 22.a.iii below, the offsets shall be obtained as close as practicable to the Shenandoah National Park boundary.

iii. The offsets shall be located within the geographic boundaries of the local or inner domain of the Shenandoah National Park airshed for oxidized nitrogen deposition as defined by Figure IV-8.a of the National Park Service report Assessment of Air Quality and Related Values in the Shenandoah National Park (May 2003).

b. The offsets shall be in effect prior to startup of the equipment listed in Condition 1.

c. Prior to commencing operation, the permittee shall provide to the Director, Valley Region, official certification from the air pollution control agency that regulates each source which provides offsets that the offsets meet the requirements of Condition 22.a., at a minimum documenting that the emissions reductions obtained as offsets are recognized by the agency as surplus (not otherwise required by regulation), permanent, and federally enforceable. The document shall state that the emissions reduction has not been and will not be credited toward another reduction requirement. The facility shall not commence operation until the Director, Valley Region, has approved in writing the certification and/or other documentation submitted by the permittee pursuant to this subsection as satisfying the requirements of Condition 22.a.

d. The permittee shall maintain at the permitted facility a copy of the following:

i. Identification of each source from which offsets were obtained. Identification shall include the name, address and Universal Transverse Mercator (UTM) coordinates of the facility and any identification number assigned to the facility by the air pollution control authority that regulates it.

ii. Certification document from each air pollution control agency required by Condition 22.c. and any supporting documentation.

(9 VAC 5-170-160)

**<u>OPERATING/EMISSION LIMITATIONS – EMERGENCY UNITS (EG1 & EG2)</u>**

23. **Fuel: Prior to the Final Implementation Date of Federal Motor Vehicle Diesel Fuel Standards** - Prior to the final implementation date of the federal standards for motor vehicle diesel fuel at retail outlets and wholesale purchaser-consumer facilities contained in 40 CFR 80.500 and 40 CFR 80.520, the approved fuel for the emergency fire water pump (EG1) and the emergency generator (EG2) is distillate fuel oil with a maximum sulfur content per shipment of 0.05% by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1705 and 9 VAC 5-80-1715)

24. **Fuel: After the Final Implementation Date of Federal Motor Vehicle Diesel Fuel Standards** – After the final implementation date of federal standards for motor vehicle diesel fuel at retail outlets and wholesale purchaser-consumer facilities contained in 40 CFR 80.500 and 40 CFR 80.520, the approved fuel for the emergency fire water pump (EG1) and the emergency generator (EG2) is distillate fuel oil with a maximum sulfur content per shipment of 0.0015% by weight. A change in the fuel may require a permit to modify and operate.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1705 and 9 VAC 5-80-1715)

25. **Operating Hours: Emergency Firewater Pump** - The emergency fire water pump (EG1) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

26. **Operating Hours: Emergency Generator** - The emergency generator (EG2) shall not operate more than 500 hours per year, calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months. The emergency generator (EG2) shall operate only when neither combustion turbine (CT1 or CT2) is operating or for testing or maintenance.
(9 VAC 5-80-1180 and 9 VAC 5-80-1715)

27. **Fuel Certification** - The permittee shall obtain a certification from the fuel supplier with each shipment of distillate oil. Each fuel supplier certification shall include the following:

a. The name of the fuel supplier;

b. The date on which the distillate oil was received;

c. The volume of distillate oil delivered in the shipment; and

d. The sulfur content of the distillate oil.

Fuel sampling and analysis, independent of that used for certification, as may be periodically required or conducted by DEQ may be used to determine compliance with the fuel specifications stipulated in Condition 23 or 24, as applicable. Exceedance of these specifications may be considered credible evidence of the exceedance of emission limits
(9 VAC 5-80-1180)

28. **Emission Limits -** Emissions from the operation of the emergency firewater pump (EG1) shall not exceed the limits specified below:

| | | |
|---|---|---|
| Non-methane Hydrocarbons plus Nitrogen Oxides (as $NO_2$) | 2.0 lbs/hr | 0.5 tons/yr |
| Carbon Monoxide | 1.7 lbs/hr | 0.4 tons/yr |

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 25.
(9 VAC 5-50-260, 9 VAC 5-80-1180, 9 VAC 5-80-1715 and 40 CFR 60.4205(c))

29. **Emission Limits -** Emissions from the operation of the emergency generator (EG2) shall not exceed the limits specified below:

| | | |
|---|---|---|
| Non-methane Hydrocarbons plus Nitrogen Oxides (as $NO_2$) | 23.6 lbs/hr | 5.9 tons/yr |
| Carbon Monoxide | 12.8 lbs/hr | 3.2 tons/yr |

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition 26.
(9 VAC 5-50-260, 9 VAC 5-80-1180 9 VAC 5-80-1715 and 40 CFR 60.4205(b))

30. **Requirements by Reference** - Except where this permit is more restrictive than the applicable requirement, the firewater pump (EG1) and the emergency generator (EG2) described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart IIII.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

## OPERATING/EMISSION LIMITATIONS – AUXILIARY BOILER (AB1) (SCENARIOS 2 AND 3)

31. **Fuel (Scenarios 2 and 3)** – The approved fuel for the auxiliary boiler (AB1) is pipeline natural gas with a maximum sulfur content of 0.0003 percent by weight (i.e., 0.1 grain or less of total sulfur per 100 standard cubic feet). A standard cubic foot of gas is defined as a cubic foot of gas at standard conditions as specified in 40 CFR 72.2 (68°F and 29.92 in Hg). A change in the fuel may require a permit to modify and operate.
(9 VAC 5-80-1180)

32. **Fuel Throughput (Scenarios 2 and 3)** – The auxiliary boiler (AB1) shall consume no more than 316 million cubic feet of natural gas per year (Scenario 2) or 201 million cubic feet of natural gas per year (Scenario 3), calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.
(9 VAC 5-80-1180)

33. **Emission Limits (Scenarios 2 and 3)** - Emissions from the operation of the auxiliary boiler (AB1) shall not exceed the limits specified below:

| Pollutant | Scenario 2 | | Scenario 3 | |
|---|---|---|---|---|
| Nitrogen Oxides (as $NO_2$) | 0.011 lb/MMBtu | 1.82 tons/yr | 0.011 lb/MMBtu | 1.16 tons/yr |
| Carbon Monoxide | 0.036 lb/MMBtu | 5.96 tons/yr | 0.036 lb/MMBtu | 3.78 tons/yr |
| Sulfur Dioxide | 0.32 lbs/hr | 0.55 tons/yr | 0.20 lbs/hr | 0.35 tons/yr |
| Volatile Organic Compounds | 0.58 lbs/hr | 0.99 tons/yr | 0.37 lbs/hr | 0.63 tons/yr |

These emissions are derived from the estimated overall emission contribution from operating limits. Exceedance of the operating limits shall be considered credible evidence of the exceedance of emission limits. Compliance with the annual emission limits may be determined as stated in Condition numbers 31 and 32.
(9 VAC 5-80-1180)

34. **Visible Emission Limit (Scenarios 2 and 3)** - Visible emissions from the auxiliary boiler (AB1) stack shall not exceed 10 percent opacity as determined by EPA Method 9 (reference 40 CFR 60, Appendix A).
(9 VAC 5-80-1180)

35. **Requirements by Reference (Scenarios 2 and 3) -** Except where this permit is more restrictive than the applicable requirement, the auxiliary boiler (AB1) as described in Condition 1 shall be operated in compliance with the requirements of 40 CFR 60, Subpart Dc.
(9 VAC 5-50-400 and 9 VAC 5-50-410)

## CONTINUOUS EMISSION MONITORING SYSTEMS (CEMS)

36. **CEMS -** Continuous Emission Monitoring Systems (CEMS) shall be installed to measure and record the emissions of $NO_x$ (measured as $NO_2$) and CO, in ppmvd corrected to 15% $O_2$, from each combined cycle unit (CC1 & CC2). CEMS for $NO_x$ shall meet the design specifications of 40 CFR 75 whereas CEMS for CO shall be installed, evaluated, and operated according to the "Monitoring Requirements"' in 40 CFR 60.13. The CEMS shall also measure and record the oxygen content of the flue gas at each location where $NO_x$ and CO emissions are monitored and measure heat input and power output. A CEMS shall also be installed to measure sulfur dioxide to comply with the requirements of 40 CFR 75 (acid rain program monitoring), unless an alternative method of determining sulfur dioxide emissions has been approved by EPA Region III for that purpose. For compliance with the emission limits contained in Condition 13, $NO_x$ data shall be reduced to 1-hour block averages where CO data shall be reduced to 3-hour block averages. The relative accuracy test audit (RATA) of the $NO_x$ CEMS shall be performed on a lb/MMBtu basis.
(9 VAC 5-50-40, 9 VAC 5-80-420, 40 CFR 75, 40 CFR 60.13 and 40 CFR 60.4340(b))

37. **CEMS Performance Evaluations -** Performance evaluations of the $NO_x$ and sulfur dioxide continuous monitoring systems shall be conducted in accordance with 40 CFR 75, Appendix A, and shall take place during the performance tests under 9 VAC 5-50-30 or within 30 days thereafter. One copy of the performance evaluation report shall be submitted to the Director, Valley Region, within 45 days of the evaluation. The continuous monitoring systems shall be installed and operational prior to conducting initial performance tests. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation and calibration of the device. A 30-day notification, prior to the demonstration of the continuous monitoring system's performance, and subsequent notifications shall be submitted to the Director, Valley Region.
(9 VAC 5-50-40, 40 CFR 75 and 40 CFR 60.4345(a))

38. **CEMS Quality Control Program -** A CEMS quality control program which is equivalent to the requirements of 40 CFR 60.13 and 40 CFR 60, Appendix F shall be implemented for all continuous monitoring systems.
(9 VAC 5-50-40, 40 CFR 60.13, 40 CFR 60.4345(e) and 40 CFR 60)

39. **Excess Emissions and Monitor Downtime for $NO_x$ - Continuous Monitoring Systems** For the purpose of this permit, periods of excess emissions and monitor downtime that must be reported under Condition 41 are defined as follows:

    a. An excess emissions is any unit operating period in which the one-average hour $NO_x$ emission rate exceeds the applicable emission limit in Condition 13; and

    b. A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: $NO_x$ concentration, $O_2$ concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if the permittee uses this information for compliance purposes.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c) and 40 CFR 60.4380)

40. **Excess Emissions and Monitor Downtime for $SO_2$ - Continuous Monitoring Systems** Excess emissions and monitoring downtime are defined, for the purpose of this permit, as follows:

    a. An excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit; and

    b. A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

    (9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c) and 40 CFR 60.4385)

41. **Reports for Continuous Monitoring Systems -** The permittee shall furnish written reports to the Director, Valley Region, of excess emissions from any process monitored by a continuous emission monitoring system (CEMS) on a quarterly basis, postmarked no later than the 30th day following the end of calendar quarter. These reports shall include, but are not limited to, the following information:

a. The magnitude of excess emissions, any conversion factors used in the calculation of excess emissions, and the date and time of commencement and completion of each period of excess emissions;

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, or malfunctions of the process, the nature and cause of the malfunction (if known), the corrective action taken or preventative measures adopted;

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments;

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired or adjusted, such information shall be stated in that report; and

e. Excess emission reports for sulfur dioxide and nitrogen dioxide as required in 40 CFR 60.4395.

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c), 40 CFR 60.4375(a) and 40 CFR 60.4395)

42. **Excess Emissions for Continuous Monitoring Systems –** For purposes of identifying excess emissions:

a. All CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h);

b. For each operating hour in which a valid hourly average, as described in 40 CFR 60.4345(b), is obtained for both $NO_x$ and diluent monitors, the data acquisition and handling system must calculate and record the hourly $NO_x$ emission rate in units of ppm, using the appropriate equation in 40 CFR Part 60, Appendix A, Method 19. For any hour in which the hourly average $O_2$ concentration exceeds 19.0 percent $O_2$, a diluent cap value of 19.0 percent $O_2$ may be used in the emission calculations;

c. Correction of measured $NO_x$ concentrations to 15 percent $O_2$ is not allowed; and

d. Only quality assured data from the CEMS shall be used to identify excess emissions. Periods where the missing data substitution procedures in 40 CFR 75, Subpart D are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under 40 CFR 60.7(c).

(9 VAC 5-50-50, 9 VAC 5-50-410, 40 CFR 60.7(c) and 40 CFR 60.4350)

**RECORDS**

43. **On Site Records** - The permittee shall maintain records of emission data and operating parameters as necessary to demonstrate compliance with this permit. The content and format of such records shall be arranged with the Director, Valley Region. The records shall include, but are not limited to:

a. Annual throughput of natural gas to each CT (CT1 & CT2), calculated monthly as the sum of each consecutive 12-month period.

b. Annual throughput of natural gas to each duct burner (DB1 & DB2) calculated monthly as the sum of each consecutive 12-month period.

c. Time, date and duration of each startup, shutdown, reduced load, and malfunction period for each combined cycle power generating unit (CC1 & CC2).

d. Annual number of startup and shutdown occurrences, calculated monthly as the sum of each consecutive 12-month period (CC1 & CC2).

e. Records to verify sulfur content of pipeline natural gas as required in Condition 12.

f. Continuous records of heat input for each combined cycle power generating unit (CC1 & CC2).

g. Continuous records of power output from combined cycle power generating units (CC1 & CC2) and the steam turbine generator(s).

h. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 14, 28 and 29, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the Director, Valley Region.

i. Continuous monitoring system emissions data, calibrations and calibration checks, percent operating time, and excess emissions.

j. Annual hours of operation for the emergency fire water pump (EG1) and the emergency generator (EG2), calculated monthly as the sum of each consecutive 12-month period.

k. All fuel supplier certifications for the emergency units (EG1 & EG2).

l. Operation and control device monitoring records for each SCR system and each oxidation catalyst.

m. Ammonia slip monitoring results.

n. Scheduled and unscheduled maintenance and operator training.

o. Results of all stack tests, visible emission evaluations, visible emission inspection results, and performance evaluations.

**For Scenarios 2 and 3**

p. Monthly and annual throughput of natural gas to the auxiliary boiler (AB1) calculated monthly as the sum of each consecutive 12-month period. Compliance for the consecutive 12-month period shall be demonstrated monthly by adding the total for the most recently completed calendar month to the individual monthly totals for the preceding 11 months.

q. Records to verify sulfur content of pipeline natural gas as required in Condition 31.

r. Emissions calculations sufficient to verify compliance with the annual emission limitations in Conditions 33, calculated monthly as the sum of each consecutive 12-month period. Calculation methods shall be approved by the Director, Valley Region.

These records shall be available for inspection by the DEQ and shall be current for the most recent five years.
(9 VAC 5-50-50)

**TESTING**

44. **Testing/Monitoring Ports** - The permitted facility shall be constructed so as to allow for emissions testing upon reasonable notice at any time, using appropriate methods. This includes constructing the facility such that volumetric flow rates and pollutant emission rates can be accurately determined by applicable test methods and providing stack or duct that is free from cyclonic flow. Test ports shall be provided in accordance with the applicable performance specification (reference 40 CFR Part 60, Appendix B).
(9 VAC 5-50-30 F)

45. **Initial Performance Test – Combustion Turbines** - Initial performance tests shall be conducted on each combined cycle unit (CC1 & CC2) for the following pollutants using the specified methods:

| **Pollutant** | **Test Method** |
|---|---|
| Carbon Monoxide (CO) | 40 CFR 60, Appendix A, Method 10 |
| Volatile organic compounds (VOC) | 40 CFR 60, Appendix A, Method 25A |

| Pollutant | Test Method |
|---|---|
| PM-10 (All particulate matter shall be considered PM-10 and shall include condensables) | 40 CFR 60, Appendix A, Methods 5 or 17 and 19, and 40 CFR 51, Appendix M, Method 202 |

Tests shall be conducted to determine compliance with the emission limits contained in Condition 13. The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. CO, VOC and PM-10 emissions shall be determined at each of the operating conditions indicated for each pollutant contained in Condition 13. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Region, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

46. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combined cycle unit (CC1 & CC2) for oxides of nitrogen (as $NO_2$) to determine compliance with the limits contained in Condition 13 as follows:

a. 40 CFR 60, Appendix A, Methods 7E or 20 shall be used to measure the $NO_x$ concentration (in parts per million (ppm)). Sampling traverse points for $NO_x$ and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals. The sampling must be performed with a traversing single-hole probe, or, if feasible, with a stationary multi-hole probe that samples each of the points sequentially. Alternatively, a multi-hole probe designed and documented to sample equal volumes from each hole may be used to sample simultaneously at the required points.

b. Notwithstanding Condition 46.a. above, the permittee may test at fewer points than are specified in Method 1 or Method 20 if the following conditions are met: The permittee may perform a stratification test for $NO_x$ and diluent pursuant to the procedures specified in 40 CFR 75, Appendix A, Section 6.5.6.1(a) through (e). Once the stratification sampling is completed, the permittee may use the following alternative sample point selection criteria for the performance test:

i. If each of the individual traverse point $NO_x$ concentrations is within ±10 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±5ppm or ±0.5 percent $O_2$ from the mean for all traverse points, three points (located either 16.7, 50.0 and 83.3 percent of the way across the stack or duct, or, for circular stacks or ducts greater than 2.4 meters (7.8 feet) in diameter, at

0.4, 1.2, and 2.0 meters from the wall) may be used. The three points must be located along the measurement line that exhibited the highest average $NO_x$ concentration during the stratification test; or

ii. The permittee may sample at a single point, located at least 1 meter from the stack wall or at the stack centroid if each of the individual traverse point $NO_x$ concentrations is within ±2.5 percent of the mean concentration for all traverse points, or the individual traverse point diluent concentrations differs by no more than ±1ppm or ±0.15 percent $O_2$ from the mean for all traverse points.

c. The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. Testing maybe performed at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. Three separate test runs for each performance test must be conducted. The minimum time per run is 20 minutes.

d. The permittee must measure the total $NO_x$ emissions after the duct burner rather than directly after the turbine. The duct burner must be in operation during the performance test.

e. Compliance with the applicable emission limit in Condition 13 must be demonstrated at each tested load level. Compliance is achieved if the three-run arithmetic average $NO_x$ emission rate at each tested level meets the applicable emission limit in Condition 13.

f. The performance evaluation of the CEMS may either be conducted separately or (as described in 40 CFR 60.4405) as part of the initial performance test of the affected unit.

g. The ambient temperature must be greater than 0°F during the performance test.

h. The permittee may use the following as alternatives to the reference methods and procedures specified in this condition:

i. Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0°F during the RATA runs.

ii. Compliance with the applicable emission limit in Condition 13 is achieved if the arithmetic average of all of the $NO_x$ emission rates for the RATA runs, expressed in units of ppm, does not exceed the emission limit.

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Region, within 45 days after test completion but no later than 180 days after startup of the permitted unit and shall conform to the test report format enclosed with this permit.

(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8, 40 CFR 60.4405 and 40 CFR 60.4400)

47. **Initial Performance Test – Combustion Turbines –** Initial performance tests shall be conducted on each combined cycle unit (CC1 & CC2) for sulfur dioxide ($SO_2$) to determine compliance with the limits contained in Condition 13. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

   a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

   b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the $SO_2$ concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, “Flue and Exhaust Gas Analyses,” manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

   c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the $SO_2$ and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit. Tests shall be conducted and

reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Region, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410, 40 CFR 60.8 and 40 CFR 60.4415)

48. **Initial Performance Test – Auxiliary Boiler (Scenarios 2 and 3) –** Initial performance tests shall be conducted on the auxiliary boiler for $NO_x$ and CO to determine compliance with the emission limits contained in Condition 33. The tests shall be performed, reported, and demonstrate compliance within 60 days after the boiler reaches the maximum load level at which the unit will be operated but in no event later than 180 days after its initial startup. Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Region, within 45 days after test completion but no later than 180 days after startup of the permitted boiler and shall conform to the test report format enclosed with this permit
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

49. **Compliance Demonstration – Duct Burners** – The permittee shall determine compliance with the $NO_x$ emission limits in Condition 16 by complying with the $NO_x$ emission limits contained in Condition 13.
(9 VAC 5-50-30, 9 VAC 5-50-410 and 40 CFR 60.4400 (b)(2))

50. **Visible Emissions Evaluation – Combustion Turbines -** Concurrently with the initial performance tests, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on each combined cycle generating unit stack. Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. At least one VEE shall be conducted for each of the operating scenarios and loads for which emissions tests are required for the stack tests contained in Condition 45. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the unit will be operated but in no event later than 180 days after start-up of the permitted unit.

Should conditions prevent concurrent opacity observations, the Director, Valley Region, shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall

be submitted to the Director, Valley Region, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30 and 9 VAC 5-80-1180)

51. **Visible Emissions Evaluation - Auxiliary Boiler (Scenarios 2 and 3) -** Concurrently with the initial performance tests in Condition 48, Visible Emission Evaluations (VEE) in accordance with 40 CFR Part 60, Appendix A, Method 9, shall be conducted by the permittee on the auxiliary boiler (AB1). Each test shall consist of 30 sets of 24 consecutive observations (at 15 second intervals) to yield a six-minute average. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. The evaluation shall be performed, reported, and demonstrate compliance within 60 days after achieving the maximum production rate at which the boiler will be operated but in no event later than 180 days after start-up of the boiler.

    Should conditions prevent concurrent opacity observations, the Director, Valley Region, shall be notified in writing, within seven days, and visible emissions testing shall be rescheduled within 30 days. Rescheduled testing shall be conducted under the same conditions (as possible) as the initial performance tests. One copy of the test result shall be submitted to the Director, Valley Region, within 45 days after test completion but no later than 180 days after startup of the permitted facility and shall conform to the test report format enclosed with this permit.
    (9 VAC 5-50-30 and 9 VAC 5-80-1180)

## CONTINUING COMPLIANCE DETERMINATION

52. **Annual Performance Test – Combustion Turbines –** Annual performance tests shall be conducted on each combined cycle unit (CC1 & CC2) for sulfur dioxide ($SO_2$) to determine compliance with the limits contained in Condition 13. The permittee may use one of the following three methods (a., b. or c. below) to conduct the performance test:

    a. If the permittee chooses to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see 40 CFR 60.17) for natural gas. The fuel analyses may be performed either by the permittee, a service contractor retained by the permittee, the fuel vendor, or any other qualified agency. The samples for the total sulfur content of the fuel shall be analyzed using ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see 40 CFR 60.17).

    b. 40 CFR 60, Appendix A, Methods 6, 6C, 8, or 20 shall be used to measure the $SO_2$ concentration (in parts per million (ppm)). In addition, the American Society of Mechanical Engineers (ASME) standard, ASME PTC 9–10–1981–Part 10, "Flue and Exhaust Gas Analyses," manual methods for sulfur dioxide (incorporated by reference, see 40 CFR 60.17) can be used instead of EPA Methods 6 or 20.

c. 40 CFR 60, Appendix A, Methods 6, 6C, or 8 and 3A, or 20 shall be used to measure the $SO_2$ and diluent gas concentrations. In addition, the permittee may use the manual methods for sulfur dioxide ASME PTC 19–10–1981–Part 10 (incorporated by reference, see 40 CFR 60.17).

The tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). Tests shall be conducted and reported and data reduced as set forth in 9 VAC 5-50-30 and the test methods and procedures contained in each applicable section or subpart listed in 9 VAC 5-50-410. The details of the tests are to be arranged with the Director, Valley Region. The permittee shall submit a test protocol at least 30 days prior to testing. One copy of the test results shall be submitted to the Director, Valley Region, within 45 days after test completion and shall conform to the test report format enclosed with this permit.
(9 VAC 5-50-30, 9 VAC 5-80-1180, 9 VAC 5-50-410 and 40 CFR 60.4415(a))

53. **Stack Tests** - Upon request by the DEQ, the permittee shall conduct additional performance tests to demonstrate compliance with the emission limits contained in this permit. The details of the tests shall be arranged with the Director, Valley Region.
(9 VAC 5-50-30 G)

54. **Visible Emissions Evaluation – Combustion Turbines** – The permittee shall conduct visible emission inspections on each combined cycle generating unit stack in accordance with the following procedures and frequencies:

a. At a minimum of once per week, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed the applicable standard, the VEE shall be conducted for a total of 60 minutes.

b. If visible emissions inspections conducted during 12 consecutive weeks show no visible emissions for a particular unit stack, the permittee may reduce the monitoring frequency to once per month for that unit stack. Anytime the monthly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per week for that stack.

c. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

55. **Visible Emissions Evaluation – Auxiliary Boiler (Scenarios 2 and 3)** – The permittee shall conduct visible emission inspections on the auxiliary boiler (AB1) stack in accordance with the following procedures and frequencies:

a. At a minimum of once per month, the permittee shall determine the presence of visible emissions. If during the inspection, visible emissions are observed, a visible emission evaluation (VEE) shall be conducted in accordance with 40 CFR 60, Appendix A, EPA Method 9. The VEE shall be conducted for a minimum of six minutes. If any of the observations exceed 10 percent opacity, the VEE shall be conducted for a total of 60 minutes.

b. All visible emissions inspections shall be performed when the boiler is operating.

c. If visible emissions inspections conducted during 12 consecutive months show no visible emissions, the permittee may reduce the monitoring frequency to once per quarter. Anytime the quarterly visible emissions inspections show visible emissions, or when requested by DEQ, the monitoring frequency shall be increased to once per month.

d. All visible emission inspections, observations and VEE results shall be recorded.

(9 VAC 5-50-20)

## NOTIFICATIONS

56. **Initial Notifications** - The permittee shall furnish written notification of the following to the Director, Valley Region:

a. The selection of one of the three possible scenarios (Scenario 1, 2 or 3) for the final configuration of the electrical power generation facility, postmarked not less than 30 days prior to construction commencement of the electric power generation facility.

b. The actual date on which construction of the electric power generation facility commenced, within 30 days after such date.

c. The anticipated start-up date of the electric power generation facility, postmarked not more than 60 days nor less than 30 days prior to such date.

d. The actual start-up date of the electric power generation facility, within 15 days after such date.

e. The anticipated date of continuous monitoring system performance evaluations, postmarked not less than 30 days prior to such date.

f. The anticipated date of performance tests of the electric power generation facility, postmarked at least 30 days prior to such date.

Copies of the written notification referenced in items b through f above are to be sent to:

Associate Director
Office of Air Enforcement (3AP10)
U.S. Environmental Protection Agency
Region III
1650 Arch Street
Philadelphia, PA 19103-2029

(9 VAC 5-50-50 and 9 VAC 5-50-410)

## GENERAL CONDITIONS

57. **Permit Invalidation** - This permit to construct and operate an electric power generation facility shall become invalid, unless an extension is granted by the DEQ, if:

a. A program of continuous construction is not commenced before the latest of the following:

i. Eighteen months from the date of the most recent permit amendment;

ii. Nine months from the date that the last permit or other authorization was issued from any other governmental agency;

iii. Nine months from the date of the last resolution of any litigation concerning any such permits or authorization; or

b. A program of construction is discontinued for a period of 18 months or more, or is not completed within a reasonable time.

c. DEQ may extend the 18-month period upon a satisfactory showing that an extension is justified.

d. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date.

(9 VAC 5-80-1210 and 9 VAC 5-80-1785 B)

58. **Permit Suspension/Revocation** - This permit may be suspended or revoked if the permittee:

a. Knowingly makes material misstatements in the application for this permit or any amendments to it;

b. Fails to comply with the conditions of this permit;

c. Fails to comply with any emission standards applicable to a permitted emissions unit;

d. Causes emissions from this facility which result in violations of, or interferes with the attainment and maintenance of, any ambient air quality standard; or

e. Fails to operate this facility in conformance with any applicable control strategy, including any emission standards or emission limitations, in the State Implementation Plan in effect at the time an application for this permit is submitted.

(9 VAC 5-80-1210 F and 9 VAC 5-80-1985)

59. **Right of Entry** - The permittee shall allow authorized local, state, and federal representatives, upon the presentation of credentials:

a. To enter upon the permittee's premises on which the facility is located or in which any records are required to be kept under the terms and conditions of this permit;

b. To have access to and copy at reasonable times any records required to be kept under the terms and conditions of this permit or the State Air Pollution Control Board Regulations;

c. To inspect at reasonable times any facility, equipment, or process subject to the terms and conditions of this permit or the State Air Pollution Control Board Regulations; and

d. To sample or test at reasonable times.

For purposes of this condition, the time for inspection shall be deemed reasonable during regular business hours or whenever the facility is in operation. Nothing contained herein shall make an inspection time unreasonable during an emergency.
(9 VAC 5-170-130)

60. **Maintenance/Operating Procedures** - At all times, including periods of start-up, shutdown, and malfunction, the permittee shall, to the extent practicable, maintain and operate the affected source, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions.

The permittee shall take the following measures in order to minimize the duration and frequency of excess emissions, with respect to air pollution control equipment, monitoring devices, and process equipment which affect such emissions:

a. Develop a maintenance schedule and maintain records of all scheduled and non-scheduled maintenance.

b. Maintain an inventory of spare parts.

c. Have available written operating procedures for equipment. These procedures shall be based on the manufacturer's recommendations, at a minimum.

d. Train operators in the proper operation of all such equipment and familiarize the operators with the written operating procedures. The permittee shall maintain records of the training provided including the names of trainees, the date of training and the nature of the training.

Records of maintenance and training shall be maintained on site for a period of five years and shall be made available to DEQ personnel upon request.

(9 VAC 5-50-20 E)

61. **Record of Malfunctions** - The permittee shall maintain records of the occurrence and duration of any bypass, malfunction, shutdown or failure of the facility or its associated air pollution control equipment that results in excess emissions for more than one hour. Records shall include the date, time, duration, description (emission unit, pollutant affected, cause), corrective action, preventive measures taken and name of person generating the record.
(9 VAC 5-20-180 J)

62. **Notification for Facility or Control Equipment Malfunction** - The permittee shall furnish notification to the Director, Valley Region, of malfunctions of the affected facility or related air pollution control equipment that may cause excess emissions for more than one hour, by facsimile transmission, telephone or telegraph. Such notification shall be made as soon as practicable but not later than four daytime business hours after the malfunction is discovered. The permittee shall provide a written statement giving all pertinent facts, including the estimated duration of the breakdown, within 14 days of the discovery. When the condition causing the failure or malfunction has been corrected and the equipment is again in operation, the permittee shall notify the Director, Valley Region, in writing.
(9 VAC 5-20-180 C)

63. **Violation of Ambient Air Quality Standard** - The permittee shall, upon request of the DEQ, reduce the level of operation or shut down a facility, as necessary to avoid violating any primary ambient air quality standard and shall not return to normal operation until such time as the ambient air quality standard will not be violated.
(9 VAC 5-20-180 I)

64. **Change of Ownership** - In the case of a transfer of ownership of a stationary source, the new owner shall abide by any current permit issued to the previous owner. The new owner shall notify the Director, Valley Region, of the change of ownership within 30 days of the transfer.
(9 VAC 5-80-1240 and 9 VAC 5-80-1975)

65. **Permit Copy** - The permittee shall keep a copy of this permit on the premises of the facility to which it applies.
(9 VAC 5-170-160)

# SOURCE TESTING REPORT FORMAT

Cover
1. Plant name and location
2. Units tested at source (indicate Ref. No. used by source in permit or registration)
3. Tester; name, address and report date

Certification
1. Signed by team leader / certified observer (include certification date)

* 2. Signed by reviewer

Introduction
1. Test purpose
2. Test location, type of process
3. Test dates

* 4. Pollutants tested

5. Test methods used
6. Observers' names (industry and agency)
7. Any other important background information

Summary of Results
1. Pollutant emission results / visible emissions summary
2. Input during test vs. rated capacity
3. Allowable emissions

* 4. Description of collected samples, to include audits when applicable

5. Discussion of errors, both real and apparent

Source Operation
1. Description of process and control devices
2. Process and control equipment flow diagram
3. Process and control equipment data

* Sampling and Analysis Procedures
1. Sampling port location and dimensioned cross section
2. Sampling point description
3. Sampling train description
4. Brief description of sampling procedures with discussion of deviations from standard methods
5. Brief description of analytical procedures with discussion of deviation from standard methods

Appendix

* 1. Process data and emission results example calculations

2. Raw field data

* 3. Laboratory reports

4. Raw production data

* 5. Calibration procedures and results

6. Project participants and titles
7. Related correspondence
8. Standard procedures

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* Not applicable to visible emission evaluations.